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NATIONAL TRANSPORTATION SAFETY BOARD

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Investigation of: \*

PACIFIC GAS & ELECTRIC COMPANY \*

SEPTEMBER 9, 2010 ACCIDENT \*

SAN BRUNO, CALIFORNIA \*

\* \* \* \* \*

Interview of: ROBERT FASSETT

Anaheim Room  
Marriott Hotel  
San Francisco Airport  
1800 Bayshore Highway  
Burlingame, California 94010

Friday,  
September 17, 2010

The above-captioned matter convened, pursuant to  
notice, at 3:10 p.m.

BEFORE: KARL GUNTHER  
Accident Investigator

## APPEARANCES:

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ROBERT FASSETT, Director  
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Pacific Gas & Electric Company

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1 I N T E R V I E W

2 (3:10 p.m.)

3 MR. GUNTHER: All right. I'm Karl Gunther,  
4 investigating an accident in San Bruno, California, that occurred  
5 September 9th, 2010. It's our DCA-10-MP-008.

6 And, as you're aware, you're able to have counsel. And  
7 have you chosen someone?

8 MR. FASSETT: I have.

9 MR. GUNTHER: Mr. Jaques?

10 MR. JAQUES: Dane Jaques, on behalf of the witness.

11 MR. GUNTHER: Okay. I'd like to go around the panel and  
12 everybody can introduce themselves.

13 MR. CALDWELL: Geoff Caldwell, City of San Bruno.

14 MR. DAUBIN: Brian Daubin, PG&E.

15 MR. SHORI: Sunil Shori, California Public Utilities  
16 Commission.

17 MR. KATCHMAR: United States Department of  
18 Transportation, Pipeline and Hazardous Materials Safety  
19 Administration.

20 MR. GUNTHER: Karl Gunther, NTSB. And, perhaps, later  
21 Ravi Chhatre, NTSB.

22 MS. MAZZANTI: Debbie Mazzanti, IBEW, 1245.

23 INTERVIEW OF ROBERT FASSETT

24 BY MR. GUNTHER:

25 Q. Okay. Now, can I get your name, address, and phone for

1 the record?

2 A. Sure. It's Robert P. Fassett, 375 North Wiget Lane,  
3 Walnut Creek, California 94598.

4 Q. And your job title?

5 A. I'm a Gas Engineering Director of Integrity Management  
6 and Technical Support.

7 Q. Okay. And could I get your credentials?

8 A. I have a bachelor's degree in civil engineering. I am  
9 also the National Association of Corrosion Engineers Chairman of  
10 the technical group, 041, external corrosion, direct assessment.  
11 The team is responsible for the writing and the revision of the  
12 international standard known as SP-0502, external corrosion,  
13 direct assessment.

14 Q. Okay. And are you -- do you have OQ under the  
15 competence?

16 A. I do not.

17 Q. What I'd like you to do is discuss in basic terms the  
18 PG&E integrity management program.

19 A. In general terms, there is -- well, there is a subpart  
20 O, the section that follows -- the section of maintenance falls  
21 under the definition of high consequence area. There's  
22 approximately 1,000 miles of main that falls under that  
23 definition. Approximately three-quarters of that is assessed  
24 using external corrosion direct assessment. The remaining 250 is  
25 assessed using in-line inspection. We -- we pig it at about ~~two-~~

1 one, so in order to effectively pig our pipelines, we actually pig  
2 four times more than the mileage we have to assess, relative to  
3 the definition. So there's approximately 1,000 miles of pipe to  
4 be pigged.

5 The program began in 2002 under Presidential signature.  
6 The first 10-year assessment -- we have 10 years to assess the  
7 pipeline -- is to be completed by December 2012.

8 Q. And has that been completed yet?

9 A. No, sir, but we are on schedule to complete.

10 Q. Okay.

11 MR. GUNTHER: PHMSA? Mr. Katchmar?

12 MR. KATCHMAR: You know what? I'm going to let the PUC  
13 go first.

14 MR. GUNTHER: Okay. California PUC?

15 MR. FASSETT: While they're doing that, I'll add that  
16 the program has been audited twice by the CPUC, once in 2005 and  
17 again this year.

18 MR. CHHATRE: I'm Ravi Chhatre. I will go first, and  
19 then these two guys can follow.

20 MR. GUNTHER: Okay. Ravi Chhatre will be next, NTSB.

21 BY MR. CHHATRE:

22 Q. I'm Ravi Chhatre, NTSB. <sup>11C</sup> ~~ISE~~ for this accident  
23 investigation.

24 Could you begin by giving some general description of  
25 the ECDA and how you do it, internally or consultants, and just

1 give a layman's description of how it is done?

2 A. External corrosion direct assessment -- we referred to  
3 as ECDA -- is one of the three methodologies we're allowed to use  
4 relative to the code for assessing pipelines in high consequence  
5 areas. There is also in-line inspection and there's hydro-  
6 testing.

7 ECDA is a four-step process. The process beginning with  
8 the pre-assessment, the indirect inspection, the direct  
9 examination, and then the post-assessment phase.

10 Q. And how do you do the direct and indirect assessment?

11 A. That's the second and third phase of the unit. The <sup>process R7</sup>  
12 first phase is the pre-assessment. The pre-assessment is done. <sup>to GPS the line</sup>  
13 We have -- at PG&E -- field engineers who are assigned. So the  
14 responsibility of gathering the data relative to Table 1 and 2 of  
15 the ECDA document, 0502 <sup>is theirs. R7</sup> We use that as a baseline of information  
16 when we go out to collect. It's various things about knowing  
17 about age of pipe, how the pipe was made, location of the pipe.

18 At PG&E, we do it slightly different than others, in  
19 that the field engineers also go out and have the pipeline marked  
20 and located, and then using GPS to actually shoot the pipeline in.  
21 We call that the creation of a control map. We do that because  
22 when our contractor comes in to do the indirect inspection, they  
23 are also required to GPS it. This way, we establish a control  
24 map, so that when the data comes back in, we can make sure that  
25 the data they collected is on the line we intended them to collect

1 it.

2 In that control map process, the field engineers are  
3 walking pretty much every foot of the line. They're taking down  
4 topographical information like pavement type, concrete, asphalt,  
5 soil. If they notice any other USA marks, like water or electric,  
6 they capture that. If they notice any fresh excavations, they  
7 capture that, as well.

8 That information -- all of that information is then  
9 used, evaluated by the project engineer, who gets a sense of -- an  
10 initial sense of what he thinks the integrity of the line is,  
11 what -- kind of develops a hypothesis of where he thinks corrosion  
12 may be occurring.

13 It's also at that phase that he determines or she  
14 determines if ECDA is feasible to be used on that. <sup>lie</sup> So he's  
15 evaluating the threats that ECDA is designed to assessed.

16 Generally, a pipeline -- or always a pipeline is not  
17 scheduled for ECDA if the risk management team has decided it's  
18 not feasible.

19 So, for example, if there's a long-seam threat on that  
20 pipeline, they will not be assigned for ECDA to be used as an  
21 assessment.

22 The second phase is the indirect inspection phase. The  
23 indirect inspection phase is performed by a  
24 contractor -- performed by a contractor. Generally, if it's over  
25 pavement, we use what's known as CIS -- close interval survey. We



1 drill five-eighths holes on 10-foot centers, insert a  
2 copper -- copper sulphate probe into the hole to get our pipe  
3 soils. We also use what's known as pipeline corrosion mapper,  
4 which is a wireless device design to track the current through the  
5 pipeline. When we get onto soil, we add what's called  
6 DCVG -- direct current voltage gradient -- which is another  
7 current-type tool.

8           The process or concept behind ECDA is if you have an  
9 anomaly in the coating, you may have corrosion. So we do a  
10 current survey to determine the quality of the coating. We do a  
11 pipe-to-soil survey to determine the polarization on the pipeline.

12           Once that survey is done, we evaluate the data. We have  
13 selection criteria that determines, based on the tube tools, their  
14 cross-matrix, we have severity criteria that then determines the  
15 level of prioritization, to determine where we have to dig, if  
16 anywhere.

17           The code speaks to three general categories of  
18 prioritization: immediate, scheduled, and monitored. The  
19 immediate for ECDA does not mean immediate action. It means top  
20 priority.

21           Once that's determined, then we line up for where the  
22 excavations are required. The excavation, we dig per 0502 what's  
23 called a Section 510, which is a section that tells us how many  
24 excavations we have to dig per priority if it's an immediate,  
25 scheduled, <sup>or</sup> monitor. <sup>RS</sup>

1           We perform those excavations. We have -- in the  
2 performance of that excavation, we have a very prescriptive form  
3 that we use. We call it Form H. The last time I checked, it was  
4 about 12 pages. We take just about every bit of information we  
5 can get out of the hole. We require soil samples, we take  
6 corrosion product -- if there is any. We take water samples. If  
7 any water is in the hole, we take water samples. *or RJ* If any water is  
8 under the coating. We do a full grid evaluation, map the  
9 corrosion, if any, calculate remaining strength to determine if  
10 any repairs are needed, if any corrosion was found.

11           Also, although we're not required to do it, we do that  
12 inspection after having sandblasted the pipe to do what's called  
13 an NACE 10 sandblast pattern. That provides a nice, clean  
14 surface. It makes it very easy for us to evaluate any corrosion  
15 or any other anomalies on it. It also sets us up to do something  
16 that -- that I think we led the industry in doing, which was while  
17 that hole is open, we do a full, 360-degree full length of the  
18 sandblasted pipe, wet florescent mag particle evaluation of the  
19 pipe. That tells us if there's any cracks in the pipe. Although  
20 we do not believe we have stress corrosion cracking in our system,  
21 we look every time we dig it up, whether we're doing an ECDA  
22 direct examination or we're doing an ILI direct examination. We  
23 have some 500-plus excavations now where we have full mag  
24 particle. Those exposed sections of pipe, we have not found any  
25 cracks.

1 I'm bringing this up, because, as we know, some of us  
2 suspect that the seam that failed was a ERW seam. If there was in  
3 any of our excavations an ERW seam and it was beginning to crack,  
4 the wet particle mag would pick that up.

5 Once all of the excavations are done, the data is  
6 collected, then we go into what's called the post-assessment  
7 phase. It's in the post-assessment phase that the standard  
8 requires us to evaluate the effectiveness of the process, do we  
9 still think ECDA is feasible for that pipeline?

10 We do -- in that phase, we do what we call long-term  
11 integrity management planning, which is not a requirement of the  
12 procedure, nor is it a requirement of the code. The long-term  
13 integrity management plan is to address the mitigation associated  
14 with what we may have found on the pipeline. *for example, RT* Sometimes we find  
15 that the pipe-to-soils were low, but there is no corrosion at the  
16 excavation, so we would require local maintenance to increase the  
17 *current at RT* power and the rectifiers to bring the pipe-to-soils up, that kind  
18 of thing.

19 That's sort of a Reader's Digest version of the program.

20 Q. For a Reader's Digest version, it's very good.

21 A. Thank you.

22 Q. You said one thing about a thousand miles of  
23 transmission pipeline falls into the Integrity Management Program?

24 A. It falls under the definition of high consequence areas.  
25 We have approximately 6,000 miles of what we call transmission

1 pipeline. We defined it initially as anything over 60 pounds.  
2 Relative to the program, we use the -- the code definition, and  
3 generally anything over 20 percent SMYS, <sup>of</sup> ~~we're~~ feeding a  
4 distribution center.

5 Q. Would it be automatically classified as a transmission  
6 line, irrespective of the size?

7 A. Correct.

8 Q. And you said about 700 miles of that 1,000 miles of high  
9 consequence area falls under ECDA?

10 A. Approximately three-quarters.

11 Q. Approximately. And how is the actual integrity  
12 remaining one-fourth of the transmission pipeline?

13 A. So the code requires initially when you develop your  
14 program, you have to do risk calculations for all of the pipelines  
15 in your system. And then risk-rank accordingly.

16 We use a relative risk-ranking methodology. We are  
17 moving to a pro-ballistic-based methodology.

18 Q. Which model do you use for your integrity management?

19 A. We have an analog equation that was created in-house.

20 Q. Internally?

21 A. Yes. That's correct. That equation is evaluated by  
22 subject matter experts on an annual basis. Each section of that  
23 equation is determined by the subject matter experts, whether it's  
24 still weighted properly or not.

25 Q. And is the subject matter internal or external? Meaning

1 outside consultants or PG&E expertise?

2 A. Within PG&E expertise.

3 Q. Okay. And --

4 A. I should add to that, we do have our contractor who  
5 works side-by-side with us in the ECDA, and I believe they provide  
6 comment on the annual evaluation associated with the corrosion  
7 aspect of that equation.

8 Q. Okay. So the outside contractor performs your surveys?

9 A. They perform the actual field piece of the indirect  
10 inspections.

11 Q. Okay.

12 A. And they perform the field piece of the direct  
13 examination.

14 Q. Okay. And do they analyze the data, also? Or you guys  
15 do the analysis?

16 A. The indirect inspection phase, we generated an equation  
17 that takes the data -- they create an equation and automatically  
18 places it in the appropriate level of severity.

19 Q. So your ranking -- I'm sorry, go ahead.

20 A. And then we take that data, evaluate it, determine a  
21 couple of things. We want to make sure they're -- the data they  
22 collected was on the alignment that we gave them originally.

23 So then we evaluate to determine whether we agree or not  
24 on how the classifications came in. It's auto-generated from a  
25 computer, so for the most part it --

1 Q. So human factor is pretty much kept to a minimum. You  
2 have a program that you define annually, correct? And the  
3 equation will rank -- or the equation will evaluate the data that  
4 the contractor has created?

5 A. Right. We have appropriate weightings for each factor  
6 in the equation and then it's an Excel spreadsheet, basically.

7 Q. Is the well seam a factor in the equation?

8 A. Yes.

9 Q. And what about the fast leak history, is that a factor?

10 A. Yes.

11 Q. And how do you classify the ranking? I think you  
12 mentioned it, but can you repeat that one more time? I think you  
13 said something about immediate repairs.

14 A. The prioritization in phase three of the ECDA?

15 Q. Right.

16 A. The code calls out immediate, scheduled, and monitored.

17 Q. Okay.

18 A. We've a "no indication."

19 Q. Okay. So immediate, longer, and no indication?

20 A. Immediate, scheduled --

21 Q. Right.

22 A. Scheduled is the second one. Monitor is the third one.  
23 And we have added a fourth criteria called no indication.

24 Q. Okay. So, immediate, then scheduled, then monitored and  
25 no indication?

1 A. And then we've added no indication, correct.

2 Q. Okay. All right.

3 And then going back to the inspection, are you using  
4 hydro or in-line inspection as a criterion for your evaluating the  
5 pipeline for risk assessment?

6 A. We are in general. The first baseline was -- we pretty  
7 much tried, if feasible, to pig. We've tried to pig pipelines  
8 that are greater than 30 percent ~~smice~~ <sup>S.M.Y.S. R3</sup> (ph.). If they're greater  
9 than 30 percent ~~smice~~ <sup>S.M.Y.S. R3</sup> and tape ~~coded~~ <sup>coated</sup> <sup>R3</sup>, I should say, we tried to  
10 pig them.

11 We essentially determined where we could pig first. We  
12 determined where we had long seam failure. And whether -- not  
13 long seam failure, but where we had long seam threat. Excuse me.

14 Once you determine where you have long seam threat, then  
15 you have to determine whether that's a stable threat or not. If  
16 you determine it's not a stable threat, then ECDA and the standard  
17 MFL meg flux -- ILI tools are not feasible. So you would have to  
18 use hydro tests or you would have to use an ultrasonic pig, which  
19 doesn't work very well in the gas business, because that requires  
20 moving it in a slug of water or some --

21 Q. Some conducting material? Is that what you're talking  
22 about?

23 A. Yeah, I was about to finish, though.

24 Q. I'm sorry.

25 A. So, in the gas business, because it's a dry pipe and you

1 need a couplent, you have to put the UT in. You have to put water  
2 on each side of it, which means a pig on each side of it. So it  
3 would be pig, slug of water, UT, pig, slug of water, pig.

4 The pressures in our line generally aren't sufficient to  
5 be able to push that type of tool down the line, so it's not  
6 feasible.

7 The other type of pig, which we have some experience  
8 with, is a TFI tool -- transverse field inspection tool. At the  
9 time when we were creating the baseline in 2004, that technology  
10 was still on the drafting board. It's now out. We've used it.  
11 But that technology does not -- is not big enough, I understand.  
12 It can't do a 30-inch pipe.

13 So that leaves you with hydro tests.

14 Q. So to summary, I guess it's pretty much hydro and direct  
15 assessment are the major tools you use?

16 A. The major tools are in-line inspection and ECDA.

17 Q. ECDA.

18 A. I don't believe we have any hydro tests.

19 Q. Okay.

20 A. To this point, the long seam threats that we believe we  
21 had was -- I think it was restricted to line 21-E, which is a 12-  
22 inch line, running up in our northern portion. It's called Sonoma  
23 County. And we did that -- I want to say 2008, using the TFI  
24 tool.

25 Q. So your initial baseline assessment for IM program was



1 finished in 2004, you said -- started in --

2 A. We were required to submit the baseline by 2004, and we  
3 did it.

4 Q. Okay. Did you have to submit your plan to CPUC or PHMSA  
5 before you started executing it?

6 A. No, we had to submit it to them. We didn't have to wait  
7 for permission to begin.

8 Q. Okay. So you could have started  
9 simultaneously -- submitted the plan and started your inspections?

10 A. We started with the framework, to begin the process, to  
11 understand how to do it. We worked with industry to develop the  
12 procedures which later came to be known as ECDA 0502. We and  
13 other operators. We weren't the only ones that provided the  
14 information.

15 Q. And what happens when you submit the RSPA, or PHMSA or  
16 CPUC, what are they supposed to do before you start doing  
17 monitoring with your plan? Do you require their approval of your  
18 plan?

19 A. I don't believe that the government ever tells you it's  
20 okay to use your procedure. They never tell us it's okay. They  
21 always say, "Provide us with information. And then when it comes  
22 time to audit you, we'll tell you if you have any violations."

23 Q. Okay.

24 A. That's been my experience, anyway.

25 Q. You never got any yea or nay from -- would it be CPUC or

1 PHMSA?

2 A. It would be the CPUC. PHMSA assisted. But in the  
3 development in our program, because we are also working with  
4 industry, we openly shared what we were doing with CPUC and PHMSA  
5 came out. We had a mock audit to help train PHMSA auditors on  
6 ECDA. They weren't familiar with what it was.

7 Q. Right.

8 A. PG&E was a leader in that process.

9 Q. And since 2004, were you audited for CPUC for integrity  
10 management?

11 A. We were audited in 2005 and then earlier this year.

12 Q. Okay. And did you have any comments from CPUC about  
13 your baseline assessment program? Did they cite any violations?  
14 Did they --

15 A. In 2005, PHMSA assisted CPUC in the auditing of the  
16 program. We received basically a field report out, some four  
17 pages of notes, but we never received a final letter.

18 Q. Okay.

19 A. In 2010, I think it was in April or May -- the  
20 audit -- we have not received a letter. We received some verbal  
21 notes.

22 Q. Okay.

23 A. At the close of the field meeting.

24 Q. And you mentioned that you did not -- you have not seen  
25 SCC -- external SCC on any of your transmission pipelines that was

1 excavated, sandblasted --

2 A. As part of the Subpart O, integrity management, that's  
3 correct.

4 Q. And there's no indication of any SCC on that one?

5 A. Not in -- subject to check. That's something I looked  
6 pretty hurriedly at.

7 Q. Okay.

8 A. We've not received any of that as part of the Integrity  
9 Management Program.

10 Q. Okay. What -- are you guys considering any other tools  
11 just for the cracks in the seams?

12 A. Where we have a long seam threat, we're using a TFI  
13 tool. We used it on 21-E in Sonoma County in 2008.

14 Q. And did you see any indications anywhere that you had to  
15 repair the pipe or grind it or whatever you had to do?

16 A. As I recall, we had indications. We've addressed them,  
17 but I don't -- other than that, I don't know the specifics, how  
18 many there were, how deep they were, that kind of thing.

19 Q. That's okay. And do you know how that line is different  
20 than the rest of our 9,000 or whatever -- miles of pipeline, in  
21 terms of either product, pressure, or composition?

22 A. What line are you referring to?

23 Q. The line that you said you had indications of  
24 SCC -- external SCC.

25 A. There's no external SCC.

1 Q. Internal SCC? I thought you said you had indications of  
2 internal SCC.

3 A. No, we had a long-seam threat.

4 Q. A long-seam threat, okay.

5 A. So we had a pre-70 ERW pipeline, which is known as low  
6 toughness or however you want to call it.

7 Q. Okay. And there are no indications of SCC, then? Just  
8 to make sure I get the correct information --

9 A. There are no indications of SCC.

10 Q. Okay. I want to get that in the information package.

11 Do you ever have any ruptures, leaks in the transmission  
12 pipeline in your system? And I'm not referring just to DC lines,  
13 but since you are the director, do you know of any occurrences in  
14 the past involving a transmission pipeline that had external  
15 corrosion, internal corrosion, ruptures or leaks?

16 A. Well, we have leaks. I don't recall, to my knowledge,  
17 ruptures, but I've only been here 20 years and I haven't been on  
18 the transmission side of it.

19 Q. Okay.

20 A. The only rupture -- there was a rupture in 2001, in  
21 Windsor, that I'm familiar with -- Windsor, California. It was  
22 third-party damage.

23 Q. Okay.

24 A. And then there's the rupture on September 9th, why we're  
25 here, that I'm aware of.

1 Q. Okay.

2 MR. CHHATRE: I'm done. I have no more questions.

3 Thank you very much.

4 MR. GUNTHER: PG&E?

5 BY MR. DAUBIN:

6 Q. Bob, did we ever receive -- did PG&E ever receive --  
7 from PHMSA or from CPUC any comments on the 2004 baseline?

8 A. Not that I'm aware of, but I wasn't in the capacity of  
9 reviewing that at the time. I was responsible for ECDA, I wasn't  
10 responsible for communicating with the Integrity Management  
11 Program.

12 MR. DAUBIN: That's all I have.

13 MR. GUNTHER: City of San Bruno? IBEW?

14 MS. MAZZANTI: No.

15 MR. GUNTHER: PHMSA?

16 MR. KATCHMAR: Can we go off the record, please.

17 (Off the record.)

18 (On the record.)

19 BY MR. KATCHMAR:

20 Q. Mr. Fassett, Peter Katchmar with PHMSA.

21 You mentioned in previous questions that there was a  
22 2005 integrity management inspection with PHMSA and the California  
23 PUC, a combined inspection, a combined inspection. And you said  
24 you didn't receive an actual enforcement letter or some kind of  
25 letter afterwards. But did you receive any issues -- any exit

1 interview for that inspection?

2 A. We received -- the basic, I think it was a four-page  
3 Word document. I forget how many items. But it was comments  
4 associated with the whole program. Some of it was what we called  
5 ~~RMP~~ <sup>RMP</sup> ~~Ref~~-6. That's the baseline plan, an explanation. Some of it was  
6 associated with ILI. Some of it ECDA. It was kind of a  
7 smorgasbord of comments.

8 Q. Okay. And did you do anything with those issues?

9 A. We used those issues -- if there were changes to our  
10 program that we agreed with, we incorporated them into the  
11 program. Quite a few of them were grammatical things. We had,  
12 for example, we had left the word "framework" into it, and they  
13 felt that it was a developed enough program where it should be  
14 called a procedure or a standard, not a framework. Those kinds of  
15 things.

16 There were some areas that we disagreed with and so we  
17 wrote the position papers to support why we disagreed with it.  
18 Generally, in those areas, it was not a code violation. It was  
19 just their observation or their opinion, and so we stated our  
20 opinion as to why we disagreed with their opinion.

21 And then when it came time -- so we incorporated that  
22 into our documents, where appropriate. And when it came time to  
23 prepare for the 2010 audit, we went back on that list and ensured  
24 that we had addressed it. And if we hadn't addressed it, because  
25 of paper, we ensure -- because if we wrote papers, we ensured we

1 had the papers in the audit.

2 We are compiling, at your request -- and I believe we'll  
3 have it today, if not we'll get it to you. We recreated to the  
4 best of our ability what was asked of us -- what was commented and  
5 what we did with the comments. And you should be receiving it at  
6 some point here. It's part of the investigation -- a print-out of  
7 that.

8 Q. Thank you. And you also said something about you used  
9 those issues to prepare for the PUC's 2010 audit?

10 A. Correct. We wanted to make sure we had accounted for  
11 the comments provided to us at the last time they audited us.

12 MR. KATCHMAR: Thank you. That's all have.

13 MR. GUNTHER: Sunil?

14 MR. SHORI: Yes, a couple of questions.

15 BY MR. SHORI:

16 Q. Line 132, is it pig-able in any portion between  
17 Milpitas -- between its start and terminus?

18 A. It depends on how you define "pig-able." If you mean  
19 are there lengths of <sup>some 15</sup> ~~some~~ diameters for some period of length,  
20 yes. If you mean is it pig-able meaning a single diameter for  
21 what the industry would think at least five to 10 miles to make it  
22 effective, no.

23 Q. So even on those straight stretches of fixed diameter,  
24 do you have facilities that would allow you to put the pig in and  
25 take the pig out?

1           A.    We don't have any pigging facilities on our system.  So  
2   on that system, there are no pigging facilities, I believe was  
3   your question.

4           Q.    Are there any portions of line 132 where you have the  
5   long seam identified as a threat?

6           A.    I'd have to look at the data, but I believe there  
7   is -- I believe there's some 24-inch ERW on that line, but I'd  
8   have to look at the line drawings I gave you.  You have that  
9   information.

10          Q.    In the segment where the incident occurred, what was the  
11   assessment method that you used?

12          A.    ECDA.

13          Q.    And based on that method, did you identify any  
14   indications at the location of the incident?

15          A.    Not to my knowledge.  None worth digging.  If I recall,  
16   in 2004, we had some monitors -- or 2005, we had some monitors.  I  
17   believe it was low pipe-to-soils in the 700 range.  The mitigation  
18   associated with that section was to raise the rectifier, increase  
19   the ~~volt~~ current to the pipeline.  In 2009, evaluating that area,  
20   the pipe-to-soil were above or more electro-negative than minus  
21   850 off.

22                   (Off the record.)

23                   (On the record.)

24           BY MR. SHORI:

25          Q.    At the location of the incident, did you have any long



1 seam threats identified as part of your assessment process?

2 A. I believe the data I provided you shows that our  
3 pipeline survey sheets had called that 30-inch seamless pipe.

4 Q. So is the answer no?

5 A. What was the question?

6 Q. Did you have any long seam threat identified at the  
7 location of the incident?

8 A. We did not.

9 MR. SHORI: Thank you.

10 MR. GUNTHER: Okay. Ravi?

11 MR. FASSETT: Just to clarify, it was not identified  
12 prior to the incident.

13 MR. CHHATRE: Just a couple of follow-up questions.

14 BY MR. CHHATRE:

15 Q. Your outside consultant, contractor, performs ECDA and  
16 then the contractor analyzes the data and send you a report. Is  
17 that a correct summary?

18 A. The contractor has programming that takes each  
19 individual data point from the different tools and provides by  
20 station essentially -- categorizes relative to the criteria we  
21 gave them.

22 We then take that data and determine where we will  
23 excavate.

24 Q. Okay.

25 A. They don't decide where we will excavate.

1 Q. They analyze and they tell you, "This is where we  
2 see -- these 10 locations we feel" -- or whatever it may be.

3 Now, who watches that? Who internally checks that the  
4 contractor's work is satisfactory, adequate, correct?

5 A. So the contractor has a senior engineer that evaluates  
6 all of the data. They have 100 percent quality control evaluation  
7 of the data to determine it makes sense to them.

8 Then it comes over to us and our project engineer  
9 evaluates that data. He has to do a couple of things. It's not  
10 just take the data, but he has to look at that data, look at the  
11 selection criteria, look back at the pre-assessment information  
12 that he gathered, where he made his initial hypothesis of where he  
13 thinks he would be looking. He needs to verify that those two  
14 assumptions are still kind of in -- all in a line, if you will.

15 And then the decisions are made. So he's evaluating all  
16 of the data and then the decisions are made where to dig.

17 Q. Any occasions where -- let me back up.

18 The person who does that, what's the title would be?

19 A. He's a ECDA project engineer.

20 Q. Okay. And does he have corrosion -- I guess training  
21 background -- to do that or is this training internally by PG&E?  
22 What is the person's background?

23 A. Well, he's certainly gone through NACE CP-1 through  
24 CP-3.

25 Q. Okay.

1 A. He was trained by a NACE CP Level 4, who is also a  
2 metallurgist. Who also provides the training and support for our  
3 newer --

4 Q. So he's a qualified person to do that job?

5 A. Yes.

6 Q. And how do you decide where to excavate? What are  
7 PG&E's criteria?

8 A. The specific criteria is provided in our <sup>RMP. R+</sup> ~~R&PO~~-9, which I  
9 believe we provided to you for evaluation. I don't remember it to  
10 the detail that I could speak to it at this point.

11 Q. Okay. So who made that decision? Obviously not you.  
12 Where to excavate --

13 A. The project engineer.

14 Q. The project engineer. Would it be the same person who  
15 looks at the data or a different person?

16 A. The same person.

17 Q. The same person.

18 A. That person follows it through the entire process.

19 Q. And he or she responsible for the entire 1,000 miles or  
20 700 miles that are on this pipeline or --

21 A. We have a risk management department that is responsible  
22 for calculating the risk associated with the pipeline, both in <sup>HCA's</sup> ~~HCS~~  
23 and outside of ~~HCS~~. <sup>HCA's</sup> ~~HCS~~ R+

24 Q. So the group that does it -- I am trying to find out if  
25 there's only one person in the system who makes the decision or if

1 there are a group of people who collectively make that decision.  
2 That's what I'm trying to understand.

3 A. Under integrity management, we have what we call the  
4 integrity management team. They're responsible for the actual  
5 carrying out of the inspections, whether it's ILI or ECDA or hydro  
6 test. That team reports to the manager of integrity management.  
7 The manager of integrity management has the team we call the risk  
8 management team that reports to her. And there's a team that we  
9 call system integrity, which is responsible for the processes  
10 associated with distribution of integrity management, as well as  
11 the other maintenance processes for transmission, like damage  
12 prevention, leak survey, et cetera.

13 Q. So essentially they do it and then it comes to you for  
14 approval?

15 A. The digs are approved at the manager's level.

16 Q. Okay.

17 MR. CHHATRE: Thanks. I have no more questions.

18 MR. GUNTHER: Okay. PG&E?

19 MR. FASSETT: You mean CPUC?

20 MR. GUNTHER: PG&E. City? IBEW?

21 MS. MAZZANTI: No.

22 BY MR. GUNTHER:

23 Q. All right. What I want to do is discuss since the  
24 accident and what you have observed on the pipe. What actions  
25 have you taken with regard to remediation that -- and, to some

1 extent, to what you can discuss, what actions you have planned to,  
2 you know, look at this threat and whatever threats that you may  
3 see and try to mitigate before -- you know, before -- well, let's  
4 just say to try to mitigate them.

5       A.    Okay.  So I am not a metallurgist, but I have a  
6 background in corrosion and defect assessment.  As I've discussed  
7 with the team out there -- and I think -- I won't speak for them,  
8 but I think folks on the team agree that it's likely the main  
9 failure that occurred out there where the pipe was laid open and  
10 the edges -- and the middle edges of that four-foot section that  
11 was originally just five feet south of the girth weld that broke  
12 on the north end, it looks like there was some length of  
13 incomplete penetration perhaps on a ERW seam.  It looks like there  
14 is crack growth, which fractured and with that fracture,  
15 ran -- shattered -- partially shattered the girth welds, which  
16 would have opened the pipe up.  The pipe, then, tore through its  
17 original position to the south, and that explosion forced it,  
18 broke it off the pipe to the girth weld to the north, blew it into  
19 the air and flipped it upside down.

20               In looking at the data, the data says that that pipeline  
21 should have been seamless.  In looking at the pipeline, I  
22 noticed -- and have shared these comments with the team -- that  
23 the two segments which originally would have been to the south of  
24 the rupture in orientation where we found it to be to the  
25 north -- that there are at least, possibly three -- I don't have

1 the drawings in front of me -- where there's clear signs of  
2 DSAW -- double-submersed arc-welded pipe.

3           There's a section immediately -- relative to the final  
4 position -- immediately south of it where there appears to be that  
5 final span of what I think is ERW pipe. Some of you agree with  
6 me, that may have had a hand-welded repair on the inside.

7           When I look back at our historical data in what we call  
8 gas standard A-11, page 11, we have a sheet in there that gives us  
9 a sense from accounting data of what type of pipe we bought when.  
10 So it gives us the diameter and the year and it gives us the long  
11 seam, and where it knows it gives us the smice.

12           When I look back for that year, 1956, it says -- from, I  
13 think it's '48 to '70 -- it says that historically the only pipe  
14 we bought in 30-inch was DSAW. It gave us a range of 42,000 to  
15 52,000 on the smice.

16           So what we're planning to do -- I think this is a  
17 materials issue -- we're doing this as privileged and  
18 confidential. We put a team together to kind of keep it quiet, to  
19 the degree we can, we -- NTSB has agreed that further  
20 investigation is not part of this investigation, but we will  
21 certainly share the information. The CPUC will be working with  
22 us. CPUC has given us 10 directives, one of which is to perform  
23 further assessment on the pipeline. It has not detailed as to  
24 what that assessment needs to be.

25           We're going to start with at least two assessments, as

1 referenced earlier today. We have a team put together to go back  
2 to look at all source data and verify what that was, try to  
3 rebuild the procurement processes of that day to get a better  
4 understanding of where we were buying pipe, how we were buying  
5 pipe, where it was coming into, validating -- starting with line  
6 132 -- and I would expect that it will go to line 109 and  
7 101 -- to determine, again, that's a form of assessment. We would  
8 call that an -- in ECDA terms, that would be called pre-  
9 assessment. It's still knowledge assessment of your pipe. It  
10 still gives you a lot of knowledge of what's going on and  
11 validates what we already knew. That's one of the things.

12           The other thing we're going to do is we have a  
13 camera -- a crawler camera, a 12-inch crawler camera being flown  
14 in from Canada. It has a 6,500 foot tether on it. That's going  
15 to allow us to put that camera through the pipe and the intent is  
16 to look for a long seam. If our standards are correct -- and I  
17 believe they mostly are, based on my experience -- we should be  
18 able to see where the DSAW is. And where there isn't DSAW, where  
19 there is no obvious internal seam, then that tells me it may be  
20 either seamless, <sup>LAP</sup> ~~black~~ <sup>RT</sup>-welded or ERW-welded pipe. At which point,  
21 because the camera has a footage tracker on it, we'll be able to  
22 essentially map, navigate, do that on the surface, excavate and  
23 determine what kind of pipe we have. And if it's the ERW -- I  
24 don't know if we have <sup>LAP</sup> ~~black~~-welded pipe in that size -- it is our  
25 intent to remove that from the pipeline, send that to our third

1 party consultant in Menlo Park, Exponent, at which it will be  
2 saved. We'll discuss with the NTSB and with CPUC the  
3 protocols -- and PHMSA. I assume it will be the same protocol  
4 that you'll be using in Virginia to evaluate this pipe.

5 MR. GUNTHER: Thank you. Go ahead.

6 BY MR. KATCHMAR:

7 Q. Would it make sense to put a transmitter on this camera  
8 so that you could track it from the outside of the pipe while it's  
9 going in?

10 A. That's one of the things we will be working with the  
11 manufacturer of the camera to do.

12 We also have cameras within PG&E. We have -- we use a  
13 lot of cameras for the nuclear side. We have a very sophisticated  
14 department that will be working with us in support of this. Their  
15 tethers tend to be shorter. They tend to be four or 500 feet.  
16 But, yeah, we're bringing in the best we can to address this.

17 MR. CHHATRE: Question.

18 BY MR. CHHATRE:

19 Q. On the -- you've given the number of excavations you  
20 have made in the last -- is it 507 excavations?

21 A. Some 500 of them.

22 Q. Five hundred-plus?

23 A. Plus or minus.

24 Q. Five hundred-plus. In how many years this happened?

25 A. Since the IM program started, I think we did our first



1 one --

2 Q. 2002?

3 A. -- in 2003.

4 Q. Okay. So 2003 until sometime in 2010?

5 A. Yes. And we're still doing them.

6 Q. Obviously, 500-plus, are you seeing coating -- different  
7 types of coatings in different locations?

8 A. Yeah, we have different types of coatings.

9 Approximately half of our ECDA pipe was installed in the '50s or  
10 earlier. Therefore, the majority of that pipe is hot-applied  
11 asphalt coating. Some of the younger pipes that were installed  
12 in -- I don't remember when we first started using tape. So I'd  
13 say starting in late '70s, early '80s, we were using tape and then  
14 we transitioned to FBE.

15 Q. Tape -- what tape are you talking about?

16 A. Tape-coated.

17 Q. Tape coating, okay.

18 A. And then we used fusion-bonded epoxy, which is what we  
19 use today. On some of our directional boring crossings, we have  
20 other coatings, <sup>Power-cure RT</sup>~~power-cure~~ and that kind of thing.

21 Q. Okay. Those 500-plus excavations, would they be  
22 probably in the same kind of percentage in terms of coating?

23 A. I don't know.

24 Q. Okay. I'm trying to -- okay, let me ask it a different  
25 way.

1           What kind of coating problems you have observed when you  
2 did the excavation? Did you observe the condition of the  
3 coating -- or somebody in PG&E observe the condition of the  
4 coating?

5           A.    Yeah, generally there are times when the hot-applied  
6 asphalt has dis-bonded or easily dis-bond<sup>RT</sup> To my knowledge, we  
7 have not found any shielded tape-coated pipe. We have found dis-  
8 bonded tape coat and we have found that with the ECDA tools. To  
9 my knowledge, we have not found any cold tar coating. We have  
10 some lines that have Somastic coating. That's about it.

11          Q.    Now, in any case -- in any of the situations, there are  
12 200-plus -- 500-plus -- were there any corrosion associated with  
13 the coating problems? I mean are you guys keeping track of that?

14          A.    How do you define "associated with"?

15          Q.    Meaning -- those 500-plus cases, to sandblast you have  
16 to remove the coating. You first excavated. Did you examine the  
17 coating from the outside before you removed it? Condition of the  
18 coating is what I'm talking about.

19          A.    Yes, we look at the condition of the coating. All of  
20 that information is kept on Form H.

21          Q.    Form H?

22          A.    Yeah. Which is referenced in the binders that you have.

23          Q.    Okay.

24          A.    And is discussed in the procedure.

25          Q.    And, I guess, my next question is, depending on the

1 coating condition, have you observed any general corrosion  
2 fittings underneath those coatings?

3 A. Yes.

4 Q. And in the coating condition, what kind of actions did  
5 you have to mitigate that?

6 A. Generally there's enough remaining strength in the pipe  
7 where repairs are not required.

8 Q. And that would be decided based on -- do you do the  
9 calculations on the remaining strength? Is that how you determine  
10 that you don't need to do anything on that?

11 A. Yes, we use KAPPA or R-strength.

12 Q. Okay. And so in most of the cases you're seeing no  
13 repair or corrective actions are necessary?

14 A. Correct. There have been some repairs, but in most  
15 cases, if there was corrosion found, it was not deep enough to  
16 require repair.

17 Q. Was any of that captured in the ~~DEBG~~ *DEVG R7*?

18 A. Was any of what captured in that?

19 Q. The corrosion damage underneath the coating. Was it  
20 picked up in any shape or form in the --

21 A. We would have done it generally, because we believe  
22 there is corrosion there. That's why we would have excavated  
23 there.

24 Q. Oh, okay. So part of your excavation, I guess selection  
25 criteria, is the location that may be more prone to corrosion? I

1 think what you're saying that your consultant didn't dictate where  
2 you can excavate. You decided.

3 A. We have criteria, it's established in there, as to  
4 what's an immediate. So I'm running off of memory. If you have a  
5 close interval survey and it has minus 500 only, that's enough  
6 to -- just on its own is to call it as an immediate. And then  
7 there's, you know, some sense of more electro-positive than 850,  
8 with some sense of current evaluation from the PCM, could give you  
9 an immediate or a scheduled. All of that is laid out in the  
10 procedure. I don't have it memorized.

11 Q. That's okay.

12 BY MR. DAUBIN:

13 Q. So Bob -- Brian Daubin, PG&E. Was it safe to say that  
14 the ECDA digs that you have are based on criteria and the  
15 prioritization of the results from ECDA?

16 A. From the results of the indirect --

17 Q. Assessment?

18 A. -- assessment, yes.

19 MR. DAUBIN: Thanks.

20 MR. CHHATRE: That helps. That helps.

21 BY MR. CHHATRE:

22 Q. And any leaks -- either external or internal leaks -- on  
23 the transmission lines?

24 A. Are there any leaks on the transmission lines?

25 Q. Past leaks.

1 A. The what?

2 Q. In the past history, since -- this goes back to 2002.

3 A. Yes, there are leaks.

4 Q. And can you --

5 A. And there's repairs.

6 Q. I'm sorry?

7 A. There's leaks and there's repairs.

8 Q. Okay. And --

9 A. We generally don't -- even though technically we can  
10 leave an open leak on a transmission line, depending on the grade,  
11 we don't typically do that. We pretty much repair all leaks on  
12 the transmission line.

13 Q. And can you describe -- maybe give me a couple of  
14 examples of what the leaks look like or what the cause was or do  
15 you do a root cause on those?

16 A. If we did a root cause, it would be in our records. The  
17 kinds of corrosion we see, is that what you're asking?

18 Q. Um-hum.

19 A. So we see classic rock impingement-type corrosion. We  
20 see general corrosion, general corrosion with pitting in it. That  
21 type of thing.

22 MR. CHHATRE: Okay. Thanks. I'm done.

23 MR. GUNTHER: Okay. Anybody have any more questions?

24 BY MR. KATCHMAR:

25 Q. Bob, to use KAPPA, don't they need to use ~~Sharpe~~ <sup>Charpi</sup> <sup>RJ</sup> (ph.)

1 values to plug in that?

2 A. No, if you have them, it helps. But you don't have to.

3 Q. Okay.

4 A. KAPPA was John's -- John Kiefner was funded through  
5 industry, PRCI, to create R-string. Industry funded it and then  
6 PRCI, even though they received funding from industry and, I  
7 believe, from the government, turned around and started charging  
8 people for it. That annoyed John. He wrote KAPPA and put it out  
9 on the internet.

10 Q. Right.

11 A. KAPPA is essentially ~~R-string~~ *R-string*.

12 Q. I've used it. That's why I asked the question.

13 Could you please go over your -- just in general terms,  
14 your risk assessment for line segments that could affect HCAs and  
15 how that's evolved from the first list to today?

16 A. I'll do my best, but I haven't been directly involved in  
17 the creation.

18 We use -- we started with Method One, which is all Class  
19 Threes and Class Two and Class One, where 50 or more people -- 20  
20 or more people congregated 50 or more days out of the year. Not  
21 to be continuous.

22 And then we had -- because we had a GIS system, we  
23 purchased aerial photography and were able to use Method Two,  
24 which is the potential impact radius, calculation. It's a moving,  
25 potential impact radius, which is referred to as a Siefert Circle,

1 ASME B318-S and I don't remember if it's in Subpart O, but it says  
2 you can do assessments by B318-S and it's in B318-S.

3 So we use that method to determine what segments of the  
4 line need to be addressed. Did that explain your question?

5 MR. GUNTHER: Off the record.

6 (Off the record.)

7 (On the record.)

8 BY MR. KATCHMAR:

9 Q. Okay. Could you go into a little more detail about how  
10 your risk assessments -- or baseline assessments -- I guess it's  
11 risk assessments changed between your 2002 and 2004 and 2005 --

12 A. Sure. So, as I mentioned earlier, Subpart O requires us  
13 to calculate the risk of all of our segments. And I think -- I'm  
14 going off memory, but I think there's <sup>20,000 ft</sup>~~40,000~~ transmission segments  
15 and somewhere to that, plus or minus, in GIS.

16 So we run the calculation, evaluate it. We actually  
17 started risk management in '99, prior to Subpart O.

18 We put -- using that analog equation, we put number  
19 values on them. They're relative risk values, they're not  
20 probabilistic. It's more about this pipe looks worse than this  
21 other pipe, which looks better than the other pipe, but not as bad  
22 as the first pipe type of concept.

23 So we have -- and we can provide kind of a general graph  
24 of how many segments we had in which level of risk priority. So  
25 we had taken -- for high risk, for example, I believe that it's

1 the number of 1,950 to 3,500, or somewhere in that area. And we  
2 have a graph that we can produce that shows what it looked like in  
3 2001 and what it looks like in 2009, after a series of mitigation.  
4 Not just integrity management mitigation, but we have what we call  
5 the risk management program, which we take from that list as we  
6 continue to drive down risk, because of all of the mitigation we  
7 perform on it through DA and ILI.

8           We drive that down through a program we call Risk  
9 Management Top 100. That's an annual capital investment in some  
10 portion of the top 100 highest risk pipelines.

11           And that calls for -- sometimes that calls for  
12 replacement. Sometimes that calls for doing close interval survey  
13 or evaluation to get more information about just how accurate that  
14 risk calculation is. That helps to drive down the risk of the  
15 pipeline.

16           So we are -- because it is a deterministic or  
17 relativistic methodology, and because you have a continuous  
18 integrity management program after you get done with the survey,  
19 you're required to come back at least seven years later and do it  
20 again. You are effectively driving the risk to zero, because you  
21 will continuously drive this.

22           So what may have been -- what may have been in 2001 the  
23 top 100 ran from 3,200 points to 3,500 points, or  
24 whatever -- 3,200 to 3,500 -- you look at the top 100 today and it  
25 will be far lower than that.



1           As I recall at one point, the graph has 120 segments  
2 that had a risk of like 1,950 in 2001, and if you look at it  
3 today, there's like 10 segments that have a risk of 1,950 on it.  
4 And we can break that down in points of 50, and we have that  
5 aspect.

6           So between integrity management and between this Risk  
7 Management Top 100 program, we have consistently driven the risk  
8 of the pipelines down year over year and we can show you graphical  
9 form, if you like.

10       Q.    So suffice it to say with a relativistic approach, you  
11 always have a hundred in the top risks?

12       A.    Yes.

13       MR. KATCHMAR: Thank you.

14       MR. GUNTHER: All right. Any more questions?

15       MR. CHHATRE: I guess one question and it really deals  
16 with this one piece of paper that was, I guess, referred to by the  
17 media all of the time with the Vice Chairman and with my meeting  
18 with the Governor.

19       BY MR. CHHATRE:

20       Q.    What is that piece of paper that PG&E submitted to  
21 either -- I think the CPUC or somebody about its risk? There is  
22 some paper -- what is the document that PG&E has submitted -- and  
23 I'm not sure -- where it classifies some high-risk pipeline very  
24 nearby, going north of the rupture site?

25       A.    I'm assuming it comes from the top 100 list. I have not

1 seen that document. I've heard about it. I have not seen it  
2 myself. I've been involved in this investigation.

3 MR. CHHATRE: Do you -- do you have the document? Does  
4 anybody know which document it is and how do we get a copy of it?

5 MR. SHORI: A request was placed and I haven't seen it.  
6 So I know a request was placed. I'll look into getting a copy of  
7 it.

8 BY MR. CHHATRE:

9 Q. Maybe it is easier for both PG&E and CPUC to do it  
10 simultaneously, rather than waiting for one another. Obviously,  
11 you do not recall sending it. You do not -- you have no knowledge  
12 of it. So somebody at PG&E sent it, and I thought maybe it was  
13 integrity management. Because the language sounds like --

14 A. It would have been the integrity management group. But  
15 I have not been functioning in that capacity since Friday, the  
16 10th.

17 Q. I understand. Would you please find out and get  
18 us --

19 A. It's on the request list. We are working on it.

20 Q. I understand. But how do we expedite getting that  
21 document? Because I'm getting calls left and right.

22 MR. DAUBIN: Ravi, what's the request, though? I don't  
23 understand, because --

24 MR. FASSETT: Are we off the record?

25 COURT REPORTER: No.

1 MR. CHHATRE: Can you go off the record?

2 (Off the record.)

3 (On the record.)

4 MR. GUNTHER: Are there any more questions? Okay.

5 Is there anything that you haven't told us that you  
6 think in your judgment we should know?

7 MR. FASSETT: We've discussed the camera inspection,  
8 remediation. We've talked about the other team we've got looking  
9 at mapping source data for the assessment. There's also something  
10 we think may have happened out there. And this flaw was built  
11 into the pipeline back in the '50s, it had to be at the factory.  
12 So something triggered it.

13 I think there may have been some kind of geologic event,  
14 perhaps, that occurred. Whether it's settling of the pipe,  
15 undermining the pipe from leaking water main, leaking sewer,  
16 something, put -- I think may have put that pipeline into span, to  
17 some degree, had it settle.

18 What I can't tell -- it's difficult to tell from the way  
19 that pipe landed, I can't tell where the long seam was relative to  
20 the IntraDose or the ExtraDose of that bend.

21 MR. GUNTHER: We've got measurements.

22 MR. FASSETT: So if we could recreate that and get some  
23 sense of how much stress may have been on that, which could have  
24 propagated the pipe -- something triggered that. This thing  
25 couldn't sit there for 50 years and not have addressed this

1 before.

2 MR. GUNTHER: The lab will match it up and we will find  
3 out.

4 MR. FASSETT: Okay. That's what I had to offer. That's  
5 was my --

6 MR. GUNTHER: Okay. And would you like to make a  
7 statement for the record?

8 MR. FASSETT: No, thank you.

9 MR. GUNTHER: Okay. Now, we're off the record and we're  
10 done.

11 (Whereupon, the interview was concluded.)

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CERTIFICATE

This is to certify that the attached proceeding before the

NATIONAL TRANSPORTATION SAFETY BOARD

IN THE MATTER OF:           PACIFIC GAS & ELECTRIC COMPANY  
                                  SEPTEMBER 9, 2010 ACCIDENT  
                                  SAN BRUNO, CALIFORNIA  
                                  Interview of Robert Fassett

DOCKET NUMBER:           DCA-10-MP-008

PLACE:                    Burlingame, California

DATE:                     September 17, 2010

was held according to the record, and that this is the original,  
complete, true and accurate transcript which has been compared to  
the recording accomplished at the hearing.

  
Richard Frint  
Official Reporter